

SECTION 6.0

EMISSIONS FROM OTHER SOURCES

The following activities and manufacturing processes (other than benzene production or use of benzene as a feedstock) were identified as additional sources of benzene emissions: oil and gas wellheads, petroleum refineries, glycol dehydrators, gasoline marketing, publicly owned treatment works (POTWs), landfills, pulp and paper manufacturing, synthetic graphite manufacturing, carbon black manufacturing, rayon-based carbon manufacturing, aluminum casting, asphalt roofing manufacturing, and use of consumer products and building supplies.

For each of these categories, the following information is provided in the sections below: (1) a description of the activity or process, (2) a brief characterization of the national activity in the United States, (3) benzene emissions characteristics, and (4) control technologies and techniques for reducing benzene emissions. In some cases, the current Federal regulations applicable to the source category are discussed.

6.1 OIL AND GAS WELLHEADS

6.1.1 Description of Oil and Gas Wellheads

Oil and gas production (through wellheads) delivers a stream of oil and gas mixture and leads to equipment leak emissions. Emissions from the oil and gas wellheads,

including benzene, are primarily the result of equipment leaks from various components at the wellheads (valves, flanges, connections, and open-ended lines). Component configurations for wellheads can vary significantly.

Oil and gas well population data are tracked by State and Federal agencies, private oil and gas consulting firms, and oil and gas trade associations. In 1989 a total of 262,483 gas wells and 310,046 oil wells were reported in the United States.^{115,116} Reference 117 presents a comprehensive review of information sources for oil and gas well count data. The activity factor data are presented at four levels of resolution: (1) number of wells by county, (2) number of wells by State, (3) number of fields by county, and (4) number of fields by State.

6.1.2 Benzene Emissions from Oil and Gas Wellheads

Emissions from oil and gas wellheads can be estimated using the average emission factor approach as indicated in the EPA Protocol for Equipment Leak Emission Estimates.⁵⁴ This approach allows the use of average emission factors in combination with wellheads-specific data. These data include: (1) number of each type of components (valves, flanges, etc.), (2) the service type of each component (gas, condensate, mixture, etc.), (3) the benzene concentration of the stream, and (4) the number of wells.

A main source of data for equipment leak hydrocarbon emission factors for oil and gas field operations is an API study¹¹⁸ developed in 1980.

Average gas wellhead component count has been reported as consisting of 11 valves, 50 screwed connections, 1 flange, and 2 open-ended lines.¹¹⁹ No information was found concerning average component counts for oil wellheads.

Benzene and total hydrocarbons equipment leak emission factors from oil wellheads are presented in Table 6-1.¹²⁰ These emission factors were developed from

TABLE 6-1. BENZENE AND TOTAL HYDROCARBONS EQUIPMENT LEAK EMISSION FACTORS
FOR OIL WELLHEAD ASSEMBLIES^a

SCC Number	Description	Emission Source	Emission level ^b	Emission Factor		Emission Factor Rating
				Total Hydrocarbons lb/hr/wellhead (kg/hr/wellhead)	Benzene lb/hr/wellhead (kg/hr/wellhead)	
3-10-001-01	Oil wellheads ^c	Equipment leaks	1	3.67×10^{-2} (1.65×10^{-2})	1.27×10^{-7} (5.77×10^{-8})	D
			2	6.53×10^{-3} (2.97×10^{-3})	3.9×10^{-8} (1.77×10^{-8})	D
			3	9.74×10^{-4} (4.43×10^{-4})	6.25×10^{-9} (2.84×10^{-9})	D
			4	3.48×10^{-4} (1.58×10^{-4})	NA	D
			5	1.06×10^{-4} (4.82×10^{-5})	NA	D

Source: Reference 120.

^a Over 450 accessible production wellhead assemblies were screened, and a total of 28 wellhead assemblies were selected for bagging. The oil production facilities included in this study are located in California.

^b The concentration ranges applicable to the 5 emission levels developed were as follows: level 1-->10,000 ppm at two or more screening points or causing instrument flameout; level 2--3,000 to 10,000 ppm; level 3--500 to 3,000 ppm; level 4--50 to 500 ppm; level 5--0 to 50 ppm.

^c Field wellhead only. Does not include other field equipment (such as dehydrators, separators, inline heaters, treaters, etc.).

NA = Not available.

screening and bagging data obtained in oil production facilities located in California.¹²⁰ Over 450 accessible production wellhead assemblies were screened, and a total of 28 wellhead assemblies were selected for bagging. For information about screening and bagging procedures refer to Reference 54.

The composition of gas streams varies among production sites. Therefore, when developing benzene emission estimates, the total hydrocarbons emission factors should be modified by specific benzene weight percent, if available.

Benzene constituted from less than 0.1 up to 2.3 percent weight of total non-methane hydrocarbons (TNMHC) for water flood wellhead samples from old crude oil production sites in Oklahoma. Also, benzene constituted approximately 0.1 percent weight of TNMHC for gas driven wellhead samples.¹²¹ The VOC composition in the gas stream from old production sites is different than that from a new field. Also, the gas-to-oil ratio for old production sites may be relatively low.¹²¹ The above type of situations should be analyzed before using available emission factors.

6.2 GLYCOL DEHYDRATION UNITS

Glycol dehydrators used in the petroleum and natural gas industries have only recently been discovered to be an important source of volatile organic compound (VOC) emissions, including benzene, toluene, ethylbenzene, and xylene (BTEX). Natural gas is typically dehydrated in glycol dehydration units. The removal of water from natural gas may take place in field production, treatment facilities, and in gas processing plants. Glycol dehydration units in field production service have smaller gas throughputs compared with units in gas processing service. It has been estimated that between 30,000 and 40,000 glycol dehydrating units are in operation in the United States.¹²² In a survey conducted by the Louisiana Department of Environmental Quality, triethylene glycol (TEG) dehydration units accounted for approximately 95 percent of the total in the United States, with ethylene glycol (EG) and diethylene glycol (DEG) dehydration units accounting for approximately 5 percent.¹²³

Data on the population and characteristics of glycol dehydration units nationwide is limited. Demographic data has been collected by Louisiana Department of Environmental Quality, Texas Mid-Continent Oil and Gas Association and Gas Processors Association, Air Quality Service of the Oklahoma Department of Health (assisted by the Oklahoma Mid-Continent Oil and Gas Association), and Air Quality Division of the Wyoming Department of Environmental Quality.¹²⁴ Table 6-2 presents population data and characteristics of glycol dehydration units currently available.¹²⁴

6.2.1 Process Description for Glycol Dehydration Units

The two basic unit operations occurring in a glycol dehydration unit are absorption and distillation. Figure 6-1 presents a general flow diagram for a glycol dehydration unit.¹²⁵ The “wet” natural gas (Stream 1) enters the glycol dehydrator through an inlet separator that removes produced water and liquid hydrocarbons. The gas flows into the bottom of an absorber (Stream 2), where it comes in contact with the “lean” glycol (usually triethylene glycol [TEG]). The water and some hydrocarbons in the gas are absorbed by the glycol. The “dry” gas passes overhead from the absorber through a gas/glycol exchanger (Stream 3), where it cools the incoming lean glycol. The gas may enter a knock-out drum (Stream 4), where any residual glycol is removed. From there, the dry natural gas goes downstream for further processing or enters the pipeline.

After absorbing water from the gas in the absorber, the “rich” glycol (Stream 5) is preheated, usually in the still, and the pressure of the glycol is dropped before it enters a three-phase separator (Stream 6). The reduction in pressure produces a flash gas stream from the three-phase separator. Upon exiting the separator (Stream 7), the glycol is filtered to remove particles. This particular configuration of preheat, flash, and filter steps may vary from unit to unit. The rich glycol (Stream 8) then passes through a glycol/glycol exchanger for further preheating before it enters the reboiler still.

TABLE 6-2. GLYCOL DEHYDRATION UNIT POPULATION DATA

Survey	Service	No. of Units		
		Total	Capacity ≤ 10 MMscfd	Capacity > 10 MMscfd
Texas Mid-Continent Oil and Gas Association (TMOGA) and Gas Processors Association (GPA) Survey ^a	Production	618	556	62
	Gas Processing	206	103	103
	Pipeline	192	144	48
	Total	1016	803	213
Louisiana Department of Environmental Quality (LDEQ) Survey ^b	Ethylene Glycol	12	0	12
	Triethylene Glycol	191	96	95
	Total	203	96	107
Oklahoma Mid-Continent Oil and Gas Association (OKMOGA) Survey ^c	Total	1,333	NR	NR
Wyoming Department of Environmental Survey ^d	Total	1,221	1,185	36

Source: Reference 124.

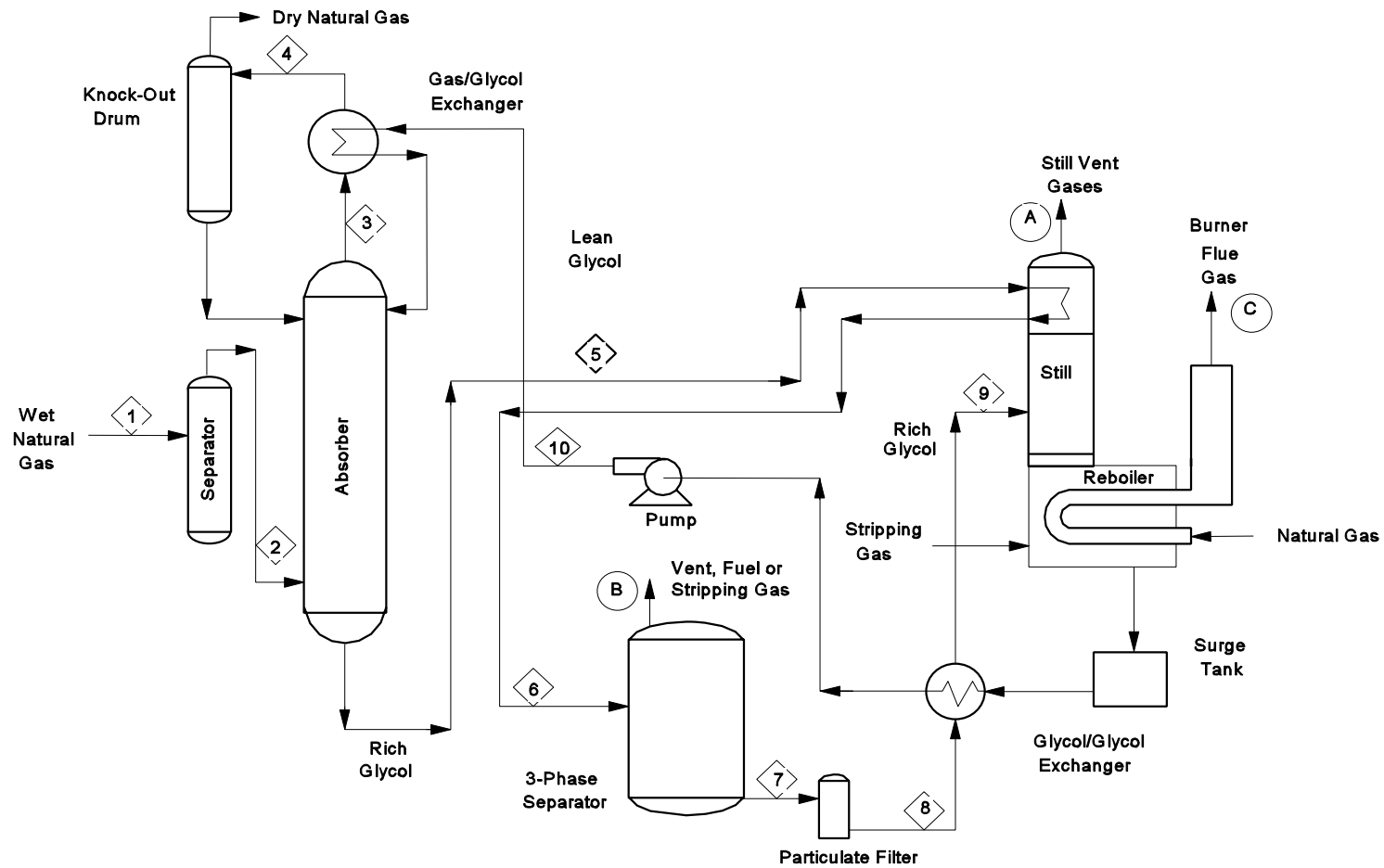
^a The survey only covers some companies; therefore it should not be considered a complete listing of units in Texas.

^b The survey was only directed to units > 5 MMscfd; therefore it should not be considered a complete listing of units in Louisiana.

^c The survey only covers dehydrator units for eight companies; therefore it should not be considered a complete listing of units in Oklahoma.

^d The survey covered 50 companies owning and/or operating glycol units in Wyoming.

NR = Not reported.



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Figure 6-1. Flow Diagram for Glycol Dehydration Unit

Source: Reference 125.

Then, the rich glycol enters the reboiler still (Stream 9) (operating at atmospheric pressure), where the water and hydrocarbons are distilled (stripped) from the glycol making it lean. The lean glycol is pumped back to absorber pressure and sent to the gas/glycol exchanger (Stream 10) before entering the absorber to complete the loop.

6.2.2 Benzene Emissions from Glycol Dehydration Units

The primary source of VOC emissions, including BTEX, from glycol dehydration units is the reboiler still vent stack (Vent A).

Because the boiling points of BTEX range from 176°F to 284°F (80 to 140°C), they are not lost to any large extent in the flash tank but are separated from the glycol in the still. These separations in the still result in VOC emissions that contain significant quantities of BTEX.¹²⁶

Secondary sources of emissions from glycol dehydration units are the phase separator vent (Vent B) and the reboiler burner exhaust stack (Vent C).

Most glycol units have a phase separator between the absorber and the still to remove dissolved gases from the warm rich glycol and reduce VOC emissions from the still. The gas produced from the phase separator can provide the fuel and/or stripping gas required for the reboiler.

A large number of small glycol dehydration units use a gas-fired burner as the heat source for the reboiler. The emissions from the burner exhaust stack are considered minimal and are typical of natural gas combustion sources.

Reboiler still vent data have been collected by the Louisiana Department of Environmental Quality,¹²³ and the Ventura County (California) Air Pollution Control District.¹²⁷ Table 6-3 presents emission factors for both triethylene glycol (TEG) units and

TABLE 6-3. REACTIVE ORGANIC COMPOUNDS (ROCs)^a AND BTEX EMISSION FACTORS FOR GLYCOL DEHYDRATION UNITS

SCC Number	SCC and Description	Emissions Source	Control Device	Emission Factor	Emission Factor Rating
69	3-10-003-01 Glycol dehydration units TEG units	Reboiler Still Vent	None	34x10 ² lb/yr of ROC/MMscfd ^b (54.46x10 ³ kg/yr of ROC/MMscmd)	U
			None	18.6x10 ² lb/yr of BTEX/MMscfd ^b (29.79x10 ³ kg/yr of BTEX/MMscmd)	U
			None	32.4x10 ² lb/yr of ROC/MMscfd ^c (51.90x10 ³ kg/yr of ROC/MMscmd)	U
	3-10-003-XX Glycol dehydration units EG units	Reboiler Still Vent	None	54.0x10 ¹ lb/yr of ROC/MMscfd ^b (8.65x10 ³ kg/yr of ROC/MMscmd)	U
			None	24x10 ¹ lb/yr of BTEX/MMscfd ^b (3.84x10 ³ kg/yr of BTEX/MMscmd)	U
			None	74.0x10 ¹ lb/yr of ROC/MMscfd ^c (11.85x10 ³ kg/yr of ROC/MMscmd)	U

^a ROC are defined as total non-methane and ethane hydrocarbons.

^b Louisiana DEQ emission factor from glycol dehydration unit survey.

^c Ventura County (California) Air Pollution Control District emission factor from one source test.

MMscfd = Million standard cubic feet per day.

MMscmd = Million standard cubic meter per day.

ethylene glycol (EG) units based on the natural gas throughput of the gas treated. The emission factors developed from the LDEQ study were based on responses from 41 companies and 208 glycol dehydration units. The Ventura County, California, factors include testing results at two locations (one for TEG and one for EG). The amount of produced gas treated is thought to be the most important because it largely determines the size of the glycol system.¹²⁷ However, the data base does not show a strong correlation because other variables with countervailing influences were not constant.¹²⁷ VOC and BTEX emissions from glycol units vary depending upon the inlet feed composition (gas composition and water content) as well as the configuration, size, and operating conditions of the glycol unit (i.e., glycol type, pump type and circulation rate, gas and contactor temperatures, reboiler fire-cycles, and inlet scrubber flash tank efficiencies).¹²⁹

The speciation of Total BTEX for TEG units reported by the LDEQ in their study indicated the following composition (% weight): benzene (35); toluene (36); ethylbenzene (5); and xylene (24). For EG units, the following compositions were reported: benzene (48); toluene (30); ethylbenzene (4); and xylene (17). Note that the BTEX composition of natural gas may vary according to geographic areas. Limited information/data on the BTEX composition is available.

Four methods for estimating emissions have been reported for glycol dehydration units: (1) rich/lean glycol mass balance, (2) inlet/outlet gas mass balance, (3) unconventional stack measurements (total-capture condensation, and partial stack condensation/flow measurement), and (4) direct stack measurements (conventional stack measurements, and novel stack composition/flow measurement).¹²⁹

Sampling of the rich/lean glycol then estimating emissions using mass balance has been the selected method for measuring emissions to date. The Louisiana Department of Environmental Quality requested emission estimates using reboiler mass balances on the rich/lean glycol samples.

Based upon a set of studies conducted by Oryx Energy Co as part of a task force for the Oklahoma-Kansas Midcontinent Oil & Gas Association, rich/lean glycol mass balance is a highly convenient, cost effective method for estimating air emissions from glycol dehydration units.¹²⁹ The following conclusions were addressed in reference 129 regarding this method: (a) good estimates of BTEX can be obtained from rich/lean glycol mass balance, (b) the rich/lean glycol mass balance BTEX estimates are in excellent agreement with total capture condensation method, and (c) rich/lean glycol mass balance is a more reproducible method for emission estimations than nonconventional stack methods. Note that conventional stack methods cannot be used on the stacks of glycol dehydration units because they are too narrow in diameter and have low flow rates.

An industry working group consisting of representatives from the American Petroleum Institute, Gas Processors Association, Texas-Midcontinent Oil & Gas Association, Louisiana Mid-Continent Oil and Gas Association, and GRI is conducting field evaluation experiments to determine appropriate and accurate sampling and analytical methods to calculate glycol dehydration unit emissions.¹²⁵ GRI has developed a computer tool, entitled GRI-GLYCalc, for estimating emissions from glycol dehydrators. The U.S. EPA has performed their own field study of GRI-GLYCalc and has recommended that it be included in EPA guidance for State/local agency use for development of emission inventories.¹³⁰

Atmospheric rich/lean glycol sampling is being evaluated as a screening technique in the above working group program. The goal is to compare these results to the stack and other rich/lean results and determine if a correction factor can be applied to this approach.¹²⁵

A second screening technique under study is natural gas sampling and analysis combined with the software program GRI-GLYCalc© to predict emissions. Table 6-4 shows the inputs required of the user and also shows the outputs returned by GRI-GLYCalc©.¹³²

TABLE 6-4. GLYCOL DEHYDRATION EMISSION PROGRAM
INPUTS AND OUTPUTS

Inputs	Units
Gas Flow Rate	MMscfd
Gas Composition	Volume percent for C ₁ -C ₆ hydrocarbons and BTEX compounds
Gas Pressure	psig
Gas Temperature	°F
Dry Gas Water Content ^a	lbs/MMscf
Number of Equilibrium Stages ^a	Dimensionless
Lean Glycol Circulation	gpm
Lean Glycol Composition	Weight % H ₂ O
Flash Temperature ^c	°F
Flash Pressure ^c	psig
Gas-Driven Pump Volume Ratio ^c	acfm gas/gpm glycol
Outputs	Units
BTEX Mass Emissions	lbs/hr or lb-moles/hr, lbs/day, tpy, vol%
Other VOC Emissions	lbs/hr or lb-moles/hr, lbs/day, tpy, vol%
Flash Gas Composition	lbs/hr or lb-moles/hr, lbs/day, tpy, vol%
Dry Gas Water Content ^b	lbs/MMscf
Number of Equilibrium Stages ^b	Dimensionless

Source: Reference 132.

^a Specify one of these inputs.

^b Dry Gas Water Content is an output if the Number of Equilibrium Stages is specified and vice versa.

^c Optional

6.2.3 Controls and Regulatory Analysis

Controls applicable to glycol dehydrator reboiler still vents include hydrocarbon skimmers, condensation, flaring, and incineration. Hydrocarbon skimmers use a three-phase separator to recover gas and hydrocarbons from the liquid glycol prior to its injection into the reboiler. Condensation recovers hydrocarbons from the still vent emissions, whereas flaring and incineration destroy the hydrocarbons present in the still vent emissions.

For glycol dehydrators it has been determined by the Air Quality Service, Oklahoma State Department of Health that the Best Available Control Technology (BACT) could include one or more of the following: (1) substitution of glycol, (2) definition of specific operational parameters, such as the glycol circulation rate, reduction of contactor tower temperature, or increasing temperature in the three-phase separator, (3) flaring/incineration, (4) product/vapor recovery, (5) pressurized tanks, (6) carbon adsorption, or (7) change of desiccant system.¹²⁸

The Air Quality Division, Wyoming Department of Environmental Quality has stated that facilities will more than likely be required to control emissions from glycol dehydration units. The Division has determined and will accept the use of condensers in conjunction with a vapor recovery system, incinerator, or a flare as representing BACT.¹³³

Most gas processors have begun to modify existing glycol reboiler equipment to reduce or eliminate VOC emissions. Some strategies and experiences from one natural gas company are presented in Reference 124. For other control technologies refer to Reference 134.

Glycol dehydration units are subject to the NSPS for VOC emissions from equipment leaks for onshore natural gas processing plants promulgated in June 1985.¹³⁵ The NSPS provides requirements for repair schedules, recordkeeping, and reporting of equipment leaks.

The Clean Air Act Amendments (CAAA) of 1990 resulted in regulation of glycol dehydration units. Title III of the CAAA regulates the emissions of 188 hazardous air pollutants (HAPs) from major sources and area sources. Title III has potentially wide-ranging effects for glycol units. The BTEX compounds are included in the list of 188 HAPs and may be emitted at levels that would cause many glycol units to be defined as major sources and subject to Maximum Achievable Control Technology (MACT).¹²⁵

Currently, the MACT standard for the oil and natural gas production source category, which includes glycol dehydration units, is being developed under authority of Section 112(d) of the 1990 CAAA and is scheduled for promulgation in May, 1999.

In addition to the federal regulations, many states have regulations affecting glycol dehydration units. The State of Louisiana has already regulated still vents on large glycol units, and its air toxics rule may affect many small units. Texas, Oklahoma, Wyoming, and California are considering regulation of BTEX and other VOC emissions from dehydration units.¹²⁵

6.3 PETROLEUM REFINERY PROCESSES

6.3.1 Description of Petroleum Refineries

Crude oil contains small amounts of naturally occurring benzene. One estimate indicates that crude oil consists of 0.15 percent benzene by volume.¹³⁶ Therefore, some processes and operations at petroleum refineries may emit benzene independent of specific benzene recovery processes. Appendix B (Table B-1) lists the locations of petroleum refineries in the U.S. As of January 1995, there were 173 operational petroleum refineries in the United States, with a total crude capacity of 15.14 million barrels per calendar day.^{137,138} The majority of refinery capacity is located in Texas, Louisiana, and California. Significant refinery capacities are also found in the Chicago, Philadelphia, and Puget Sound areas. A flow diagram

of processes likely to be found at a model refinery is shown in Figure 6-2.¹³⁹ The arrangement of these processes varies among refineries, and few, if any, employ all of these processes.

Processes at petroleum refineries can be grouped into five types: (1) separation processes, (2) conversion processes, (3) treating processes, (4) auxiliary processes and operation, and (5) feedstock/product storage and handling. These are discussed briefly below.

The first phase in petroleum refining operations is the separation of crude oil into its major constituents using four separation processes: (1) desalting, (2) atmospheric distillation, (3) vacuum distillation, and (4) light ends recovery.

To meet the demands for high-octane gasoline, jet fuel, and diesel fuel, components such as residual oils, fuel oils, and light ends are converted to gasolines and other light fractions using one or more of the following conversion processes: (1) catalytic cracking (fluidized-bed and moving-bed), (2) thermal processes (coking, and visbreaking), (3) alkylation, (4) polymerization, (5) isomerization, and (6) reforming.

Petroleum treating processes stabilize and upgrade petroleum products by separating them from less desirable products. Among the treating processes are (1) hydrotreating, (2) chemical sweetening, (3) deasphalting, and (4) asphalt blowing.

Auxiliary processes and operations include process heaters, compressor engines, sulfur recovery units, blowdown systems, flares, cooling towers, and wastewater treatment facilities.

Finally, all refineries have a feedstock/product storage area (commonly called a “tank farm”) with storage tanks whose capacities range from less than 1,000 barrels to more than 500,000 barrels. Also, feedstock/product handling operations (transfer operations) consist of the loading and unloading of transport vehicles (including trucks, rail cars, and marine vessels).

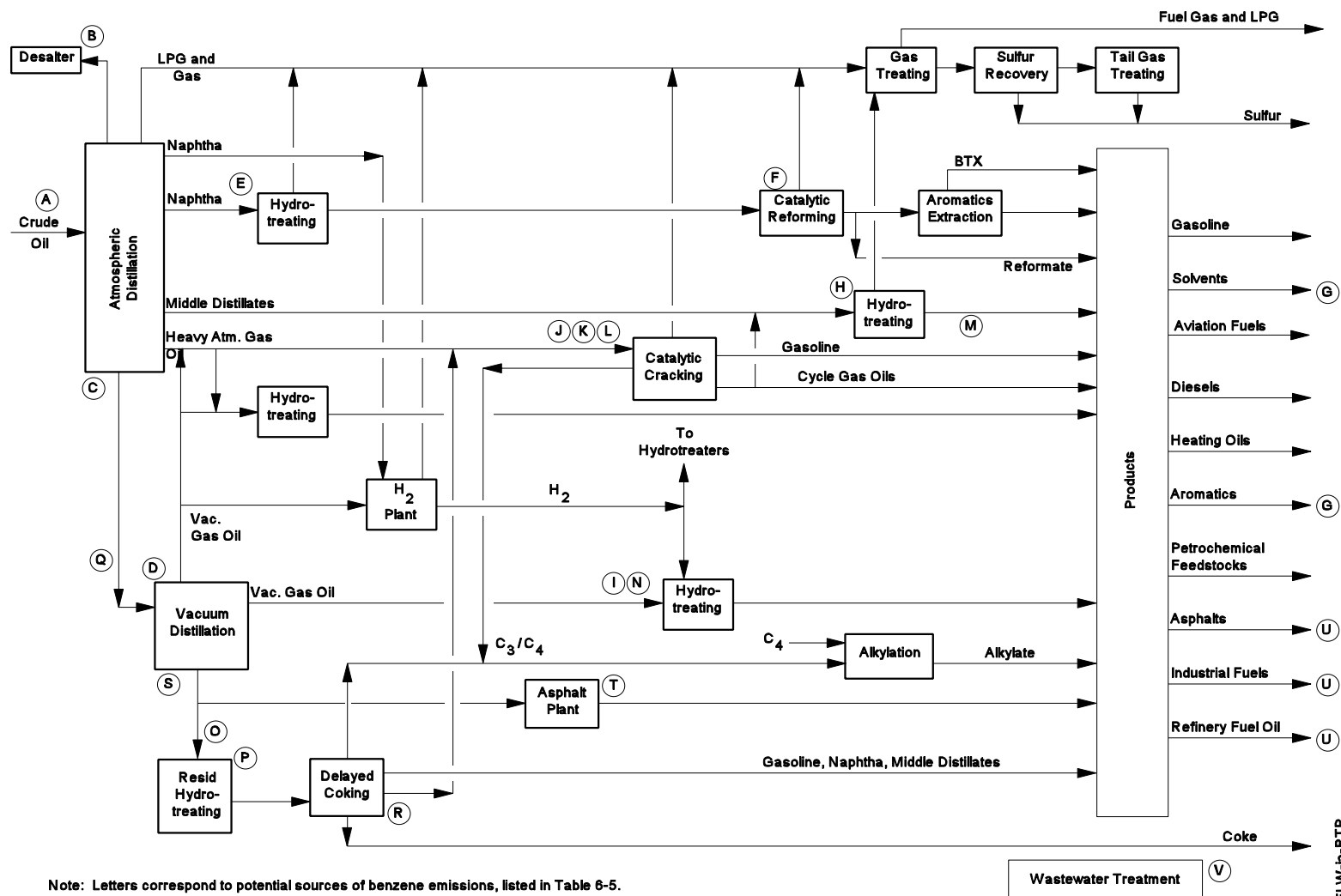


Figure 6-2. Process Flow Diagram for a Model Petroleum Refinery

Source: Reference 139.

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For a complete description of the various processes and operations at petroleum refineries refer to References 139, 140, and 141.

6.3.2 Benzene Emissions from Petroleum Refinery Processes and Operations

Benzene emissions, as well as Hazardous Air Pollutant (HAPs) emissions from petroleum refineries can be grouped into five main categories: (1) process vents, (2) storage tanks, (3) equipment leaks, (4) transfer operations, and (5) wastewater collection and treatment. Table 6-5 presents a list of specific processes and operations which are potential sources of benzene emissions at petroleum refineries emitted from one or more of the above categories.¹³⁹

Also, process heaters and boilers located at the different process units across a refinery emit flue gases containing benzene, and other HAPs. The HAPs emitted result either from incomplete combustion of fuel gas or from the combustion products.

According to the Information Collection Request (ICR) and Section 114 survey submitted to EPA by U.S. refiners as part of the Petroleum Refinery NESHAP study, benzene emissions from process vents were reported for the following process units within a refinery: (1) thermal cracking (coking), (2) Methyl Ethyl Ketone (MEK) dewaxing, and (3) miscellaneous vents at crude distillation units, catalytic reforming units, hydrotreating/hydrorefining, asphalt plants, vacuum distillation towers, and full-range distillation units (light ends, naphtha, solvent, etc.). Also, benzene emissions were reported from blowdown and flue gas system vents.

The Section 114 and ICR questionnaire responses also provided estimates of benzene concentrations in refinery processes, and in petroleum refinery products. Table 6-6 summarizes concentrations of benzene for gas, light liquid, and heavy liquid streams at some refinery process units.¹⁴² Table 6-7 summarizes concentrations of benzene in common refinery products.^{143,144}

TABLE 6-5. POTENTIAL SOURCES OF BENZENE EMISSIONS AT
PETROLEUM REFINERIES

A	Crude Storage
B	Desalting
C	Atmospheric distillation (crude unit)
D	Vacuum distillation
E	Naphtha hydrodesulfurization
F	Catalytic reforming
G	Light hydrocarbon storage and blending
H	Kerosene hydrodesulfurization
I	Gas oil hydrodesulfurization
J	Fluid bed catalytic cracking
K	Moving bed catalytic cracking
L	Catalytic hydrocracking
M	Middle distillate storage and blending
N	Lube oil hydrodesulfurization
O	Deasphalting
P	Residual oil hydrodesulfurization
Q	Visbreaking
R	Coking
S	Lube oil processing
T	Asphalt blowing
U	Heavy hydrocarbon storage and blending
V	Wastewater collection and treatment units

Source: Reference 139.

TABLE 6-6. CONCENTRATION OF BENZENE IN REFINERY PROCESS UNIT
STREAMS (WEIGHT PERCENT)

Process Unit	Stream Type		
	Gas	Light Liquid	Heavy Liquid
Crude	1.3	1.21	0.67
Alkylation (sulfuric acid)	0.1	0.23	0.23
Catalytic Reforming	2.93	2.87	1.67
Hydrocracking	0.78	1.09	0.10
Hydrotreating/hydrorefining	1.34	1.38	0.37
Catalytic Cracking	0.39	0.71	0.20
Thermal Cracking (visbreaking)	0.77	1.45	1.45
Thermal Cracking (coking)	0.24	0.85	0.18
Product Blending	1.20	1.43	2.15
Full-Range Distillation	0.83	1.33	1.08
Vacuum Distillation	0.72	0.15	0.22
Isomerization	2.49	2.49	0.62
Polymerization	0.10	0.10	0.10
MEK Dewaxing	0.36	NR	NR
Other Lube Oil Processing	1.20	1.20	0.10

Source: Reference 142.

NR means not reported.

TABLE 6-7. CONCENTRATION OF BENZENE IN REFINERY PRODUCTS

Material	Weight Percent in Liquid
Asphalt	0.03
Aviation Gasoline	0.51
Alkylate	0.12
Crude Oil	0.45
Diesel/Distillate	0.008
Gasoline (all blends)	0.90
Heavy Gas Oil	0.0002
Jet Fuel	1.05
Jet Kerosene	0.004
Naphtha	1.24
Reformates	4.61
Residual Fuel Oil	0.001
Recovered Oil	0.95

Source: References 143, 144 and 158.

Storage tanks at petroleum refineries containing petroleum liquids are potential sources for benzene emissions. VOC emissions from storage tanks, including fixed-roof, external floating-roof, and internal floating-roof types, can be estimated using *Compilation of Air Pollutant Emission Factors (AP-42)*, Chapter 7³³ and the TANKS model. Emissions of benzene from storage vessels may be estimated by applying the benzene concentrations in Table 6-7 to the equations in AP-42 which are also used in TANKS.

Equipment leak emissions from refineries occur from process equipment components such as valves, pump seals, compressor seals, pressure relief valves, connectors, open-ended lines, and sampling connections. Non-methane VOC emissions are calculated using emission factors (in lb/hr/component) and emission equations developed by the EPA in the *Protocol for Equipment Leak Emission Estimates*.⁵⁴ The number of components at a refinery are specific to a refinery. However, model equipment counts were developed for the petroleum refinery NESHAP for refineries with crude charge capacities less than 50,000 barrels/stream day (bbl/sd) and greater than or equal to 50,000 bbl/sd. These counts are presented in Tables 6-8 and 6-9.¹⁴² Benzene emissions from equipment leaks may be estimated by multiplying the equipment counts, the equipment leak factor, and the benzene concentration in the process from Table 6-6. It is generally assumed that the speciation of compounds inside a process line are equal to the compounds leaking.

The Western States Petroleum Association (WSPA) and the American Petroleum Institute (API) commissioned the development of a 1993 refinery equipment leak study¹⁴⁵ to develop new emission factors and correlation equations.¹³⁹ The data from the 1993 study has been combined with data from a 1993 marketing terminal equipment leak study.¹⁴⁶

For information on emission factors and equations for loading and transport operations, refer to Section 6.4 (Gasoline Marketing) of this document.

TABLE 6-8. MEDIAN COMPONENT COUNTS FOR PROCESS UNITS FROM SMALL REFINERIES^a

Process Unit	Valves			Pumps		Compressors	Pressure Relief Valves			Flanges			Open-ended Lines	Sampling Connections
	Gas	Light Liquid	Heavy Liquid	Light Liquid	Heavy Liquid		Gas	Light Liquid	Heavy Liquid	Gas	Light Liquid	Heavy Liquid		
Crude Distillation	75	251	216	8	8	2	6	6	5	164	555	454	39	10
Alkylation (sulfuric acid)	278	582	34	18	10	1	12	15	4	705	1296	785	20	16
Alkylation (HF)	102	402	62	13	3	2	12	13	0	300	1200	468	26	8
Catalytic Reforming	138	234	293	8	5	3	5	3	3	345	566	732	27	6
Hydrocracking	300	375	306	12	9	2	9	4	4	1038	892	623	25	10
Hydrotreating/hydrorefining	100	208	218	5	5	2	5	3	5	290	456	538	20	6
Catalytic Cracking	186	375	450	13	14	2	8	8	7	490	943	938	8	8
Thermal Cracking (visbreaking)	206	197	0	7	0	0	4	0	0	515	405	0	0	4
Thermal Cracking (coking)	148	174	277	9	8	2	7	16	13	260	322	459	13	8
Hydrogen Plant	168	41	0	3	0	2	4	2	0	304	78	0	8	4
Asphalt Plant	120	334	250	5	8	2	5	10	9	187	476	900	16	6
Product Blending	67	205	202	6	11	1	10	6	22	230	398	341	33	14
Sulfur Plant	58	96	127	6	6	3	3	88	15	165	240	345	50	3
Vacuum Distillation	54	26	84	6	6	2	2	5	2	105	121	230	16	4
Full-Range Distillation	157	313	118	7	4	2	5	4	6	171	481	210	20	6
Isomerization	270	352	64	9	2	2	7	10	1	432	971	243	7	8
Polymerization	224	563	15	12	0	1	10	5	3	150	450	27	5	7
MEK Dewaxing	145	1208	200	35	39	3	10	14	4	452	1486	2645	19	17
Other Lube Oil Processes	153	242	201	7	5	2	5	5	5	167	307	249	60	6

Source: Reference 142.

^a Refineries with crude charge capacities less than 50,000 bbl/sd.

TABLE 6-9. MEDIAN COMPONENT COUNTS FOR PROCESS UNITS FROM LARGE REFINERIES^a

Process Unit	Valves			Pumps		Compressors	Pressure Relief Valves			Flanges			Open-ended Lines	Sampling Connections
	Gas	Light Liquid	Heavy Liquid	Light Liquid	Heavy Liquid		Gas	Light Liquid	Heavy Liquid	Gas	Light Liquid	Heavy Liquid		
Crude Distillation	204	440	498	15	14	2	7	5	12	549	982	1046	75	9
Alkylation (sulfuric acid)	192	597	0	21	0	2	13	4	0	491	1328	600	35	6
Alkylation (HF)	104	624	128	13	8	1	9	11	1	330	1300	180	40	14
Catalytic Reforming	310	383	84	12	2	3	8	11	0	653	842	132	48	9
Hydrocracking	290	651	308	22	12	2	10	12	0	418	1361	507	329	28
Hydrotreating/hydrorefining	224	253	200	7	6	2	9	4	8	439	581	481	49	8
Catalytic Cracking	277	282	445	12	12	2	11	9	13	593	747	890	59	15
Thermal Cracking (visbreaking)	110	246	130	7	6	1	6	3	15	277	563	468	30	7
Thermal Cracking (coking)	190	309	250	12	11	1	8	5	10	627	748	791	100	10
Hydrogen Plant	301	58	0	7	360	3	4	139	0	162	148	0	59	21
Asphalt Plant	76	43	0	4	0	0	3	7	0	90	90	0	24	24
Product Blending	75	419	186	10	10	2	9	16	6	227	664	473	24	8
Sulfur Plant	100	125	110	8	3	1	4	4	4	280	460	179	22	7
Vacuum Distillation	229	108	447	2	12	1	5	1	4	473	136	1072	0	7
Full-Range Distillation	160	561	73	14	2	2	7	8	2	562	1386	288	54	6
Isomerization	164	300	78	9	5	2	15	5	2	300	540	265	36	7
Polymerization	129	351	82	6	2	0	7	12	28	404	575	170	17	9
MEK Dewaxing	419	1075	130	29	10	4	33	6	18	1676	3870	468	0	7
Other Lube Oil Processes	109	188	375	5	16	3	8	6	20	180	187	1260	18	9

Source: Reference 142.

^a Refineries with crude charge capacities greater than 50,000 bbl/sd.

Air emissions from petroleum refinery wastewater collection and treatment are one of the largest sources of VOC emissions at a refinery and are dependent on variables including wastewater throughput, type of pollutants, pollutant concentrations, and the amount of contact wastewater has with the air.

Table 6-10 presents model process unit characteristics for petroleum refinery wastewater.¹⁴⁷ The table includes average flow factors, average volatile HAP concentrations, and average benzene concentrations by process unit type to estimate uncontrolled emissions from petroleum refinery wastewater streams. Flow factors were derived from Section 114 questionnaire responses compiled for the Refinery NESHAP study. Volatile HAP and benzene concentrations were derived from Section 114 questionnaire responses, 90-day Benzene Waste Operations NESHAP (BWON) reports, and equilibrium calculations.

Uncontrolled wastewater emissions for petroleum refinery process units can be estimated multiplying the average flow factor, the volatile HAP concentrations, and the fraction emitted presented in Table 6-10, for each specific refinery process unit capacity.

Wastewater emission factors for oil/water separators, air flotation systems, and sludge dewatering units are presented in Table 6-11.¹⁴⁸⁻¹⁵¹

Another option for estimating emissions of organic compounds from wastewater treatment systems is to use the air emission model presented in the EPA document *Compilation of Air Pollutant Emission Factors (AP-42)*, in Section 4.3, entitled “Wastewater Collection, Treatment, and Storage.”⁶⁴ This emission model (referred to as SIMS in AP-42 and now superseded by Water 8) is based on mass transfer correlations and can predict the emissions of individual organic species from a wastewater treatment system.

TABLE 6-10. MODEL PROCESS UNIT CHARACTERISTICS
FOR PETROLEUM REFINERY WASTEWATER

Process Unit	Average flow factor ^b (gal/bbl) ^c	Average Benzene Concentration ^a		Average Volatile HAP Concentration ^a		Fraction Emitted ^f
		Value (ppmw) ^d	Origin ^e	Value (ppmw) ^d	Origin ^e	
Crude distillation	2.9	21	114	140	114	0.85
Alkylation unit	6.0	3	Eq.	6.9	Eq.	0.85
Catalytic reforming	1.5	106	Eq.	238	Eq.	0.85
Hydrocracking unit	2.6	14	114	72	114	0.85
Hydrotreating/ hydrorefining	2.6	6.3	114	32	114	0.85
Catalytic cracking	2.4	13	114	165	114	0.85
Thermal cracking/ coking	5.9	40	Eq.	75	Eq.	0.85
Thermal cracking/ visbreaking	7.1	40	Eq.	75	Eq.	0.85
Hydrogen plant	80 ^g	62	90-day	278	Ratio	0.85
Asphalt plant	8.6	40	Eq.	75	Eq.	0.85
Product blending	2.9	24	114	1,810	114	0.85
Sulfur plant	9.7 ^h	0.8	90-day	3.4	Ratio	0.85
Vacuum distillation	3.0	12	90-day	53	Ratio	0.85
Full range distillation	4.5	12	114	65	114	0.85
Isomerization	1.5	33	Eq.	117	Eq.	0.85

(continued)

TABLE 6-10. CONTINUED

Process Unit	Average flow factor ^b (gal/bbl) ^c	Average Benzene Concentration ^a		Average Volatile HAP Concentration ^a		Fraction Emitted ^f
		Value (ppmw) ^d	Origin ^e	Value (ppmw) ^d	Origin ^e	
Polymerization	3.5	0.01	90-day	0.04	Ratio	0.85
MEK dewaxing units	0.011	0.1	90-day	27	114	0.49
Lube oil/specialty processing unit	2.5	40	Eq.	75	Eq.	0.85
Tank drawdown	0.02	188	90-day	840	Ratio	0.85

Source: Reference 147.

^a Average concentration in the wastewater.

^b All flow factors were derived from Section 114 questionnaire responses.

^c gal/bbl = gallons of wastewater per barrel of capacity at a given process unit.

^d ppmw = parts per million by weight.

^e 114 = Section 114 questionnaire response; 90-day = 90-day BWON report; Eq. = Equilibrium calculation; and Ratio = HAP-to-benzene ratio (4.48).

^f These factors are given in units of pounds of HAP emitted/pound of HAP mass loading.

^g This flow factor is given in units of gallons/million cubic feet of gas production.

^h This flow factor is given in units of gallons/ton of sulfur.

TABLE 6-11. WASTEWATER EMISSION FACTORS FOR PETROLEUM REFINERIES

SCC Number	Description	Emissions Source	Control Device	Emission Factor	Factor Rating	Reference
3-06-005-08	Oil/Water Separators	Oil/water separator	Uncontrolled	1.3 lb of Benzene/10 ⁶ gal of feed water (0.16 kg of Benzene/10 ⁶ l of feed water)	E	148
				923 lb of TOC/10 ⁶ gal of feed water (111 kg of TOC/10 ⁶ l of feed water)	C	149
3-06-005-XX	Air Flotation Systems	Air flotation systems ^a	Uncontrolled	4 lb of Benzene/10 ⁶ gal of feed water (0.48 kg of Benzene/10 ⁶ l of feed water)	E	150
				30 lb of TOC/10 ⁶ gal of feed water (3.60 kg of TOC/10 ⁶ l of feed water)	B	149
3-06-005-XX	Sludge dewatering units	Sludge dewatering unit ^b	Uncontrolled	660 lb of TOC/10 ⁶ lb sludge (660 kg of TOC/10 ⁶ kg sludge)	C	151

^a Includes dissolved air flotation (DAF) or induced air flotation (IAF) systems.

^b Based on a 2.2 meter belt filter press dewatering oil/water separator bottoms, DAF float, and biological sludges at an average temperature of 125° F. ¹⁵¹

6.3.3 Controls and Regulatory Analysis

This section presents information on controls for process vents at petroleum refineries, and identifies other sections in this document that may be consulted to obtain information on control technology for storage tanks, and equipment leaks. Applicable Federal regulations to process vents, storage tanks, equipment leaks, transfer operations, and wastewater emissions are briefly described.

According to the EPA ICR and Section 114 surveys, the most reported types of control for catalyst regeneration process vents at fluid catalytic cracking units were electrostatic precipitators, carbon monoxide (CO) boilers, cyclones, and scrubbers. Some refineries have reported controlling their emissions with scrubbers at catalytic reformer regeneration vents.

For miscellaneous process vents, including miscellaneous equipment in various process units throughout the refinery, the most reported controls were flares, incinerators, and/or boilers. Other controls for miscellaneous process vents reported by refineries include scrubbers, electrostatic precipitators, fabric filters, and cyclones.

The process vent provisions included in the Petroleum Refinery NESHAP promulgated on September 18, 1995 affect organic HAP emissions from miscellaneous process vents throughout a refinery.⁴⁹ These vents include but are not limited to vent streams from caustic wash accumulators, distillation condensers/accumulators, flash/knock-out drums, reactor vessels, scrubber overheads, stripper overheads, vacuum (steam) ejectors, wash tower overheads, water wash accumulators, and blowdown condensers/accumulators.

For information about controls for storage tanks refer to Section 4.5.3 - Storage Tank Emissions, Controls, and Regulations.

Storage tanks containing petroleum liquids and benzene are regulated by the following Federal rules:

1. “National Emission Standard for Benzene Emissions from Benzene Vessels;”⁶¹
2. “Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984;”⁶² and
3. “National Emission Standards for Hazardous Air Pollutants: Petroleum Refineries.”⁴⁹

The Petroleum Refinery NESHAP requires that liquids containing greater than 4 weight percent HAPs at existing storage vessels, and greater than 2 weight percent HAPs at new storage vessels be controlled.

There are two primary control techniques for reducing equipment leak emissions: (1) modification or replacement of existing equipment, and (2) implementation of a Leak Detection and Repair (LDAR) program.

Equipment leak emissions are regulated by the New Source Performance Standards (NSPS) for Equipment Leaks of VOC in Petroleum Refineries promulgated in May 30, 1984.¹⁵² These standards apply to VOC emissions at affected facilities that commenced construction, modification, or reconstruction after January 4, 1983.

The standards regulate compressors, valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges or other connectors in VOC service.

The Benzene Equipment Leaks National Emission Standard for Hazardous Air Pollutants (NESHAP)⁵⁶ and the Equipment Leaks NESHAP⁵⁷ for fugitive emission sources regulate equipment leak emissions from pumps, compressors, pressure relief devices, sampling connecting systems, open-ended valves or lines, valves, flanges and other connectors, product

accumulator vessels, and specific control devices or systems at petroleum refineries. These NESHAPs were both promulgated in June 6, 1984.

Equipment leak provisions included in the Petroleum Refinery NESHAP require equipment leak emissions to be controlled using the control requirements of the petroleum refinery equipment leaks NSPS or the hazardous organic NESHAP.

Any process unit that has no equipment in benzene service is exempt from the equipment leak requirements of the benzene waste NESHAP. “In benzene service” means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight (as determined according to respective provisions). Any process unit that has no equipment in organic HAP service is exempt from the equipment leak requirements of the petroleum refinery NESHAP. “In organic HAP service” means that a piece of equipment contains or contacts a fluid that is at least 5 percent benzene by weight.

Refer to Section 6.4 (Gasoline Marketing) of this L&E document for information on control technologies and regulations for loading and transport operations.

For information about controls for wastewater collection and treatment systems, refer to Section 4.5.4 - Wastewater Collection and Treatment System Emissions, Controls, and Regulation.

Petroleum refinery wastewater streams containing benzene are regulated by the following Federal rules:

1. “National Emission Standard for Benzene Waste Operations;”⁶⁶
2. “New Source Performance Standard for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems;”¹⁵³ and
3. “National Emission Standards for Hazardous Air Pollutants: Petroleum Refineries.”⁴⁹

The wastewater provisions in the Petroleum Refinery NESHAP are the same as the Benzene Waste Operations NESHAP.

6.4 GASOLINE MARKETING

Gasoline storage and distribution activities represent potential sources of benzene emissions. The benzene content of gasoline ranges from less than 1 to almost 5 percent by liquid volume, but typical liquid concentrations are currently around 0.9 percent by weight.¹⁵⁸ Under Title II of the Clean Air Act as amended in 1990, the benzene content of reformulated gasoline (RFG) will be limited to 1 percent volume maximum (or 0.95 percent volume period average) with a 1.3 percent volume absolute maximum. In California, the “Phase 2 Reformulated Gasoline,” which will be required starting March 1998, also has a 1 percent volume benzene limit (or 0.8 percent volume average) with an absolute maximum of 1.2 percent volume.²⁰ For this reason, it is expected that the overall average of benzene content in gasoline will decrease over the next few years. Total hydrocarbon emissions from storage tanks, material transfer, and vehicle fueling do include emissions of benzene. This section describes sources of benzene emissions from gasoline transportation and marketing operations. Because the sources of these emissions are so widespread, individual locations are not identified in this section. Instead, emission factors are presented, along with a general discussion of the sources of these emissions.

The flow of the gasoline marketing system in the United States is presented in Figure 6-3.¹⁵³ The gasoline distribution network includes storage tanks, tanker ships and barges, tank trucks and railcars, pipelines, bulk terminals, bulk plants, and service stations. From refineries, gasoline is delivered to bulk terminals by way of pipelines, tanker ships, or barges. Bulk terminals may also receive petroleum products from other terminals. From bulk terminals, petroleum products (including gasoline) are distributed by tank trucks to bulk plants. Both bulk terminals and bulk plants deliver gasoline to private, commercial, and retail customers. Daily product at a terminal averages about 250,000 gallons (950,000 liters), in contrast to about 5,000 gallons (19,000 liters) for an average size bulk plant.¹⁵⁴

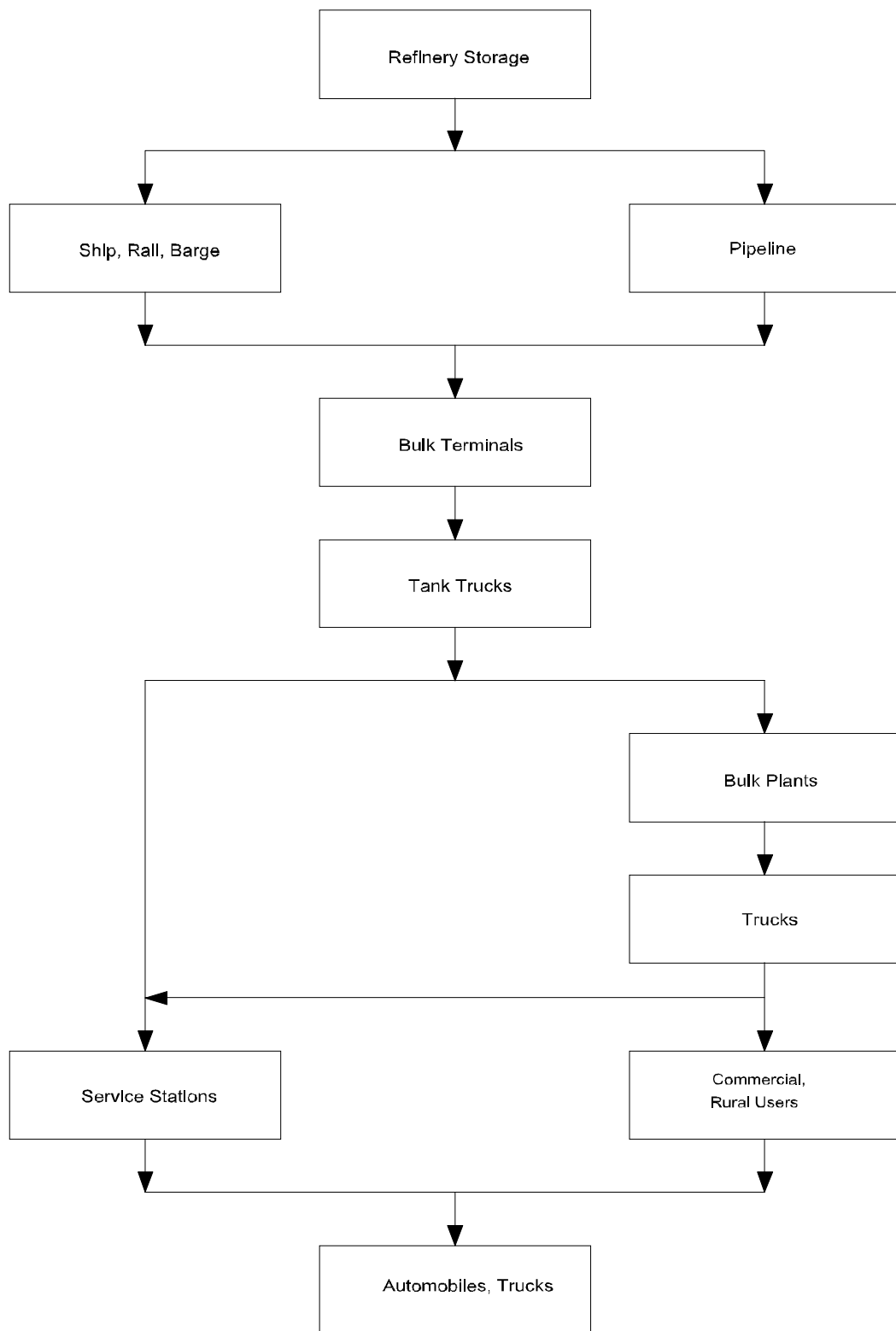


Figure 6-3. The Gasoline Marketing Distribution System in the United States

Source: Reference 153.

Service stations receive gasoline by tank truck from terminals or bulk plants or directly from refineries, and usually store the gasoline in underground storage tanks. Gasoline service stations are establishments primarily selling gasoline and automotive lubricants.

Gasoline is by far the largest volume of petroleum product marketed in the United States, with a nationwide consumption of 115 billion gallons (434 billion liters) in 1993.¹⁵⁵ There are presently an estimated 1,300 bulk terminals storing gasoline in the United States.¹⁵⁶ About half of these terminals receive products from refineries by pipeline (pipeline breakout stations), and half receive products by ship or barge delivery (bulk gas-line terminals). Most of the terminals (66 percent) are located along the east coast and in the Midwest. The remainder are dispersed throughout the country, with locations largely determined by population patterns.

The benzene emission factors presented in the following discussions were derived by multiplying AP-42 VOC emission factors for transportation and marketing¹⁵⁷ times the fraction of benzene in the vapors emitted. The average weight fraction of benzene in gasoline vapors (0.009) was taken from Reference 157. When developing emission estimates, the gasoline vapor emission factors should be modified by specific benzene weight fraction in the vapor, if available. Also a distinction should be made between winter and summer blends of gasoline (a difference in the Reid vapor pressure of the gasoline, which varies from an average of 12.8 psi in the winter to an average of 9.3 in non-winter seasons) to account for the different benzene fractions present in both.¹⁵⁸

The transport of gasoline with marine vessels, distribution at bulk plants, and distribution at service stations, their associated benzene emissions, and their controls are discussed below.

6.4.1 Benzene Emissions from Loading Marine Vessels

Benzene can be emitted while crude oil and refinery products (gasoline, distillate oil, etc.) are loaded and transported by marine tankers and barges. Loading losses are the primary source of evaporative emissions from marine vessel operations.¹⁵⁹ These emissions occur as vapors in “empty” cargo tanks are expelled into the atmosphere as liquid is added to the cargo tank. The vapors may be composed of residual material left in the “empty” cargo tank and/or the material being added to the tank. Therefore, the exact composition of the vapors emitted during the loading process may be difficult to predict.

Benzene emissions from tanker ballasting also occur as a result of vapor displacement. Ballasting emissions occur as the ballast water enters the cargo tanks and displace vapors remaining in the tank from the previous cargo. In addition to loading and ballasting losses, transit losses occur while the cargo is in transit.^{157,160}

Volatile organic compound (VOC) emission factors for petroleum liquids for marine vessel loading are provided in the EPA document *Compilation of Air Pollutant Emission Factors (AP-42)*, Chapter 5¹⁵⁷ and the EPA document *VOC/HAP Emissions from Marine Vessel Loading Operations - Technical Support Document for Proposed Standards*.¹⁵⁹

Uncontrolled VOC and benzene emission factors for loading gasoline in marine vessels are presented in Table 6-12. This table also presents emission factors for tanker ballasting losses and transit losses from gasoline marine vessels.

Table 6-13 presents total organic compound emission factors for marine vessels including loading operations, and transit for crude oil, distillate oil, and other fuels. Emissions of benzene associated with loading distillate fuel and other fuels are very low, due primarily to their low VOC emission factor and benzene content. When developing benzene emission estimates, the total organic compound emission factors presented in Table 6-13 should be multiplied by specific benzene weight fraction in the fuel vapor, if available.

TABLE 6-12. UNCONTROLLED VOLATILE ORGANIC COMPOUND AND BENZENE EMISSION FACTORS FOR LOADING, BALLASTING, AND TRANSIT LOSSES FROM MARINE VESSELS

SCC Number	Emission Source	VOC Emission Factor ^a lb/1000 gal Transferred (mg/liter Transferred)	Benzene Emission Factor ^b lb/1000 gal Transferred (mg/liter Transferred)	Emission Factor Rating
4-06-002-36/ 4-06-002-37	Ship/Ocean Barge ^c Loading Operations - Uncleaned, volatile previous cargo	2.6 (315)	0.023 (2.8)	D
4-06-002-034/ 4-06-002-035	Ship/Ocean Barge ^c Loading Operations - Ballasted; volatile previous cargo	1.7 (205)	0.015 (1.8)	D
4-06-002-36	Ship/Ocean Barge ^c Loading Operations - Cleaned; volatile previous cargo	1.5 (180)	0.014 (1.6)	D
4-06-002-31/ 4-06-002-32/ 4-06-002-36	Ship/Ocean Barge ^c Loading Operations - Any condition; nonvolatile previous cargo	0.7 (85)	0.006 (0.77)	D
4-06-002-00/ 4-06-002-40	Ship/Ocean Barge ^c Loading Operations - Typical situation, any cargo	1.8 (215)	0.016 (1.9)	D
4-06-002-38	Barge ^c Loading Operations - Uncleaned; volatile previous cargo	3.9 (465)	0.035 (4.2)	D
4-06-002-33	Barge ^c Loading Operations - Gas-free, any cargo	2.0 (245)	0.018 (2.2)	D
4-06-002-39	Tanker Ballasting	0.8 (100)	0.007 (0.9)	D
4-06-002-42	Transit	2.7 (320) ^d	0.024 (2.8) ^d	D

Source: References 157 and 159.

^a Factors are for nonmethane-nonethane VOC emissions.

^b Based on the average weight percent of benzene/VOC ratio of 0.009.¹⁵⁹

^c Ocean barge is a vessel with compartment depth of 40 feet; barge is a vessel with compartment depth of 10-12 feet.

^d Units for this factor are lb/week-1000 gal (mg/week-liter) transported.

TABLE 6-13. UNCONTROLLED TOTAL ORGANIC COMPOUND EMISSION FACTORS
FOR PETROLEUM MARINE VESSEL SOURCES^a

Emission source	Crude Oil ^b lb/10 ³ gal (mg/ℓ)	Jet Naphtha ^b lb/10 ³ gal (mg/ℓ)	Jet Kerosene lb/10 ³ gal (mg/ℓ)	Distillate Oil No. 2 lb/10 ³ gal (mg/ℓ)	Residual Oil No. 6 lb/10 ³ gal (mg/ℓ)	Emission Factor Rating
Loading operations						
Ships/ocean barge	0.61 (73)	0.50 (60)	0.005 (0.63)	0.005 (0.55)	0.00004 (0.004)	D
Barge	1.0 (120)	1.2 (150)	0.013 (1.60)	0.012 (1.40)	0.00009 (0.011)	D
Transit ^c	1.3 (150)	0.7 (84)	0.005 (0.60)	0.005 (0.54)	3x10 ⁻⁵ (0.003)	E

Source: Reference 157.

^a Emission factors are calculated for a dispensed product temperature of 60° F.

^b Nonmethane-nonethane VOC emission factors for a typical crude oil are 15 percent lower than the total organic factors shown. The example crude oil has a Reid Vapor Pressure of 5 psia.

^c Units are mg/week-ℓ transferred or lb/week-10³ gal transferred.

Each operation in which gasoline is transferred or stored is a potential source of benzene emissions. At bulk terminals and bulk plants, loading, unloading, and storing gasoline are sources of benzene emissions.

Emissions from Gasoline Loading and Unloading

The gasoline that is stored in above ground tanks at bulk terminals and bulk plants is pumped through loading racks that measure the amount of product. The loading racks consist of pumps, meters, and piping to transfer the gasoline or other liquid petroleum products. Loading of gasoline into tank trucks can be accomplished by one of three methods: splash, top submerged, or bottom loading. Bulk plants and terminals use the same three methods for loading gasoline into tank trucks. In splash loading, gasoline is introduced into the tank truck directly through a hatch located on the top of the truck.¹⁶⁰ Top submerged loading is done by attaching a downspout to the fill pipe so that gasoline is added to the tank truck near the bottom of the tank. Bottom loading is the loading of product into the truck tank from the bottom. Emissions occur when the product being loaded displaces vapors in the tank being filled. Top submerged loading and bottom loading reduce the amount of material (including benzene) that is emitted by generating fewer additional vapors during the loading process.¹⁶⁰ A majority of facilities loading tank trucks use bottom loading.

Table 6-14 lists emission factors for gasoline vapor and benzene from gasoline loading racks at bulk terminals and bulk plants.¹⁶⁰ The gasoline vapor emission factors were taken from Reference 157. The benzene factors were obtained by multiplying the gasoline vapor factor by the average benzene content of the vapor (0.009 percent).¹⁵⁸

TABLE 6-14. BENZENE EMISSION FACTORS FOR GASOLINE LOADING RACKS
AT BULK TERMINALS AND BULK PLANTS

SCC Number	Loading Method	Gasoline Vapor Emission	Benzene Emission Factor ^b lb/1000 gal (mg/liter)	Emission Factor Rating
		Factor ^a lb/1000 gal (mg/liter)		
4-04-002-50	Splash loading - normal service	11.9 (1430)	0.11 (12.9)	D
4-04-002-50	Submerged loading ^c - normal service	4.9 (590)	0.044 (5.3)	D
4-04-002-50	Balance service ^d	0.3 (40)	0.004 (0.36)	D

Source: Reference 160.

^a Gasoline factors represent emissions of nonmethane-nonethane VOC. Factors are expressed as mg gasoline vapor per liter gasoline transferred. ¹⁵⁶

^b Based on an average benzene/VOC ratio of 0.009. ¹⁵⁷

^c Submerged loading is either top or bottom submerged.

^d Splash and submerged loading. Calculated using a Stage I control efficiency of 95 percent.

Emissions from Storage Tanks

Storage emissions of benzene at bulk terminals and bulk plants depend on the type of storage tank used. A typical bulk terminal may have four or five above ground storage tanks with capacities ranging from 400,000 to 4 million gallons (1,500 to 15,000 m³).¹⁶⁰ Most tanks in gasoline service are of an external floating roof design. Fixed-roof tanks, still used in some areas to store gasoline, use pressure-vacuum vents to operate at a slight internal pressure or vacuum and control breathing losses. Some tanks may use vapor balancing or processing equipment to control working losses.

The major types of emissions from fixed-roof tanks are breathing and working losses. Breathing loss is the expulsion of vapor from a tank vapor space that has expanded or contracted because of daily changes in temperature and barometric pressure. The emissions occur in the absence of any liquid level change in the tank. Combined filling and emptying losses are called “working losses.” Emptying losses occur when the air that is drawn into the tank during liquid removal saturates with hydrocarbon vapor and is expelled when the tank is filled.

A typical external floating-roof tank consists of a cylindrical steel shell equipped with a deck or roof that floats on the surface of the stored liquid, rising and falling with the liquid level. The liquid surface is completely covered by the floating roof except in the small annular space between the roof and the shell. A seal attached to the roof touches the tank wall (except for small gaps in some cases) and covers the remaining area. The seal slides against the tank wall as the roof is raised or lowered. The floating roof and the seal system serve to reduce the evaporative loss of the stored liquid.

An internal floating-roof tank has both a permanently affixed roof and a roof that floats inside the tank on the liquid surface (contact roof), or is supported on pontoons several inches above the liquid surface (noncontact roof). The internal floating-roof rises and falls with the liquid level, and helps to restrict the evaporation of organic liquids.

The four classes of losses that floating roof tanks experience include withdrawal loss, rim seal loss, deck fitting loss, and deck seam loss. Withdrawal losses are caused by the stored liquid clinging to the side of the tank following the lowering of the roof as liquid is withdrawn. Rim seal losses are caused by leaks at the seal between the roof and the sides of the tank. Deck fitting losses are caused by leaks around support columns and deck fittings within internal floating roof tanks. Deck seam losses are caused by leaks at the seams where panels of a bolted internal floating roof are joined.

Table 6-15 shows emission factors during both non-winter and winter for storage tanks at a typical bulk terminal.¹⁵⁸ The emission factors were derived from AP-42 equations and a weight fraction of benzene in the vapor of 0.009.¹⁵⁸ Table 6-16 shows uncontrolled emission factors for gasoline vapor and benzene for a typical bulk plant.¹⁶⁰ Table 6-17 shows emission factors during both non-winter and winter months for storage tanks at pipeline breakout stations.¹⁵⁸ The emission factor equations in AP-42 are based on the same equations contained in the EPA's computer-based program "TANKS." Since TANKS is regularly updated, the reader should refer to the latest version of the TANKS program (version 3.1 at the time this document was finalized) to calculate the latest emission factors for fixed- and floating-roof storage tanks. The factors in Tables 6-15 and 6-17 were calculated with equations from an earlier version of TANKS and do not represent the latest information available. They are presented to show the type of emission factors that can be developed from the TANKS program.

Emissions from Gasoline Tank Trucks

Gasoline tank trucks have been demonstrated to be major sources of vapor leakage. Some vapors may leak uncontrolled to the atmosphere from dome cover assemblies, pressure-vacuum (P-V) vents, and vapor collection piping and vents. Other sources of vapor leakage on tank trucks that occur less frequently include tank shell flaws, liquid and vapor transfer hoses, improperly installed or loosened overfill protection sensors, and vapor couplers. This leakage has been estimated to be as high as 100 percent of the vapors which

TABLE 6-15. BENZENE EMISSION FACTORS FOR STORAGE LOSSES AT A
TYPICAL GASOLINE BULK TERMINAL

SCC Number	Storage Method	Gasoline Vapor VOC Emission Factor ^{a,b} ton/yr/Tank (Mg/yr/Tank)		Benzene Emission Factor ^c ton/yr/Tank (Mg/yr/Tank)		Emission Factor Rating
		Non-Winter	Winter	Non-Winter	Winter	
4-04-001-07/ 4-04-001-08	Fixed Roof ^d - Working Losses (Uncontrolled)	35.6 (32.3)	46.4 (42.1)	0.320 (0.291)	0.418 (0.379)	E
4-04-001-04/ 4-04-001-05	Fixed Roof ^d - Breathing Losses (Uncontrolled)	9.42 (8.55)	13.2 (12.0)	0.085 (0.077)	0.119 (0.108)	E
4-04-001-XX	External Floating Roof ^e - Working Losses	-- ^f (-- ^g)	-- ^f (-- ^g)	-- ^f (-- ^g)	-- ^f (-- ^g)	E
4-04-001-31/ 4-04-001-32	External Floating Roof ^e - Standing Storage Losses - Primary Metallic Shoe Seal and Uncontrolled Fittings	12.6 (11.4)	17.61 (15.98)	0.113 (0.103)	0.158 (0.144)	E
4-04-001-41/ 4-04-001-42	External Floating Roof ^e - Standing Storage Losses - Secondary Metallic Shoe Seal and Uncontrolled Fittings	5.9 (5.38)	8.31 (7.54)	0.035 (0.031)	0.075 (0.068)	E
4-04-001-XX	External Floating Roof ^e - Primary and Secondary Metallic Shoe Seals and Uncontrolled Fittings	3.85 (3.49)	5.38 (4.88)	0.053 (0.048)	0.048 (0.044)	E
4-04-001-XX	Internal Floating Roof ^d - Vapor-mounted Rim Seal Losses	1.12 (1.02)	1.59 (1.44)	0.0101 (0.0092)	0.0143 (0.0130)	E
4-04-001-XX	Internal Floating Roof ^d - Liquid-Mounted Seal Losses	0.51 (0.46)	0.71 (0.64)	0.0046 (0.0041)	0.0063 (0.0058)	E
4-04-001-XX	Internal Floating Roof ^d - Vapor Primary and Secondary Seal	0.42 (0.38)	0.60 (0.54)	0.0038 (0.0034)	0.0054 (0.0049)	E
4-04-001-XX	Internal Floating Roof ^d - Uncontrolled Fitting Losses ^h	1.11 (1.01)	1.56 (1.42)	0.0100 (0.0091)	0.0141 (0.0128)	E

(continued)

TABLE 6-15. CONTINUED

SCC Number	Storage Method	Gasoline Vapor VOC Emission Factor ^{a,b} ton/yr/Tank (Mg/yr/Tank)		Benzene Emission Factor ^c ton/yr/Tank (Mg/yr/Tank)		Emission Factor Rating
		Non-Winter	Winter	Non-Winter	Winter	
4-04-001-XX	Internal Floating Roof ^d - Controlled Fitting Losses ⁱ	0.76 (0.69)	1.07 (0.97)	0.0068 (0.0062)	0.0096 (0.0087)	E
4-04-001-XX	Internal Floating Roof ^d - Deck Seam Losses	0.57 (0.52)	0.80 (0.73)	0.0052 (0.0047)	0.0072 (0.0066)	E
4-04-001-XX	Internal Floating Roof ^d - Working Losses	-- ^j (-- ^k)	-- ^j (-- ^k)	-- ^j (-- ^k)	-- ^j (-- ^k)	E

Source: Reference 158.

^a Emission factors calculated with equations from Chapter 4.3 of AP-42 (TANKS program version 1.0), using a non-winter RVP of 9.3 psia, a winter RVP of 12.8 psia, and a temperature of 60°F. The reader should be aware that the TANKS program is regularly updated and that the latest version of the program should be used to calculate emission factors. At the time this document was printed, version 3.1 of the TANKS program was available.

^b Terminal with 250,000 gallons/day (950,000 liters/day) with four storage tanks for gasoline.

^c Based on gasoline emission factor and an average benzene/VOC ratio of 0.009.

^d Typical fixed-roof tank or internal floating roof tank based upon capacity of 2,680 m³ (16,750 bbls), a diameter of 50 feet (15.2 meters), and a height of 48 feet (14.6 meters).

^e Typical floating-roof tank based upon capacity of 36,000 bbls (5,760 m³), a diameter of 78 feet (24.4 meters), and a height of 40 feet (12.5 meters).

^f Gasoline vapor emission factor = $(5.1 \times 10^{-8} Q)$ ton/yr, where Q is the throughput through the tanks in barrels.

Benzene emission factor = $(4.6 \times 10^{-10} Q)$ ton/yr.

^g Gasoline vapor emission factor = $(4.6 \times 10^{-8} Q)$ Mg/yr, where Q is the throughput through the tanks in barrels.

Benzene emission factor = $(4.1 \times 10^{-10} Q)$ Mg/yr.

^h Calculated assuming the “typical” level of control in the “TANKS” program.

ⁱ Calculated assuming the “controlled” level of control in the “TANKS” program.

^j Gasoline vapor emission factor = $(8.1 \times 10^{-8} Q)$ ton/yr, where Q is the throughput through the tanks in barrels.

Benzene emission factor = $(7.3 \times 10^{-10} Q)$ ton/yr.

^k Gasoline vapor emission factor = $(7.3 \times 10^{-8} Q)$ Mg/yr, where Q is the throughput through the tank in barrels.

Benzene emission factor = $(6.6 \times 10^{-10} Q)$ Mg/yr.

-- means no data available.

TABLE 6-16. GASOLINE VAPOR AND BENZENE EMISSION FACTORS FOR A TYPICAL BULK PLANT

SCC Number	Emission Source	Gasoline Vapor Emission Factor ^a lb/1000 gal (mg/liter)	Benzene Emission Factor ^b lb/1000 gal (mg/liter)	Emission Factor Rating
4-04-002-01	Storage Tanks - Fixed Roof - Breathing Loss	5.0 (600)	0.5 (5.4)	E
4-04-002-04	Storage Tanks - Fixed Roof - Working Loss:			
	Filling	9.6 (1150)	0.086 (10.3)	E
	Emptying	3.8 (460)	0.034 (4.1)	E
4-04-002-50	Gasoline Loading Racks:			
	Splash Loading (normal service)	11.9 (1430)	0.107 (12.9)	E
	Submerged Loading (normal service)	4.9 (590)	0.044 (5.3)	E
	Splash and Submerged Loading (balance service) ^c	0.3 (40)	0.002 (0.4)	E

Source: Reference 160.

^a Typical bulk plant with gasoline throughput of 19,000 liters/day (5,000 gallons/day).^b Based on gasoline emission factor and an average benzene/VOC ratio of 0.009.^c Calculated using a Stage I control efficiency of 95 percent.

TABLE 6-17. BENZENE EMISSION FACTORS FOR STORAGE LOSSES AT A
TYPICAL PIPELINE BREAKOUT STATION^{a,b}

SCC Number	Storage Method	Gasoline Vapor VOC Emission Factor ^{a,b} ton/yr/Tank (Mg/yr/Tank)		Benzene Emission Factor ^c ton/yr/Tank (Mg/yr/Tank)		Emission Factor Rating
		Non-Winter	Winter	Non-Winter	Winter	
4-04-00X-XX	Fixed Roof Uncontrolled - Breathing Losses	36.9 (33.5)	52.0 (47.2)	0.332 (0.302)	0.468 (0.425)	E
4-04-00X-XX	Fixed Roof Uncontrolled - Working Losses	477.5 (433.3)	621.5 (564.0)	4.297 (3.9)	5.6 (5.1)	E
4-04-00X-XX	Internal Floating Roof - Vapor-mounted rim seal losses	2.26 (2.05)	3.16 (2.87)	0.020 (0.018)	0.028 (0.026)	E
4-04-00X-XX	Internal Floating Roof - Liquid-mounted rim seal losses	1.01 (0.92)	1.42 (1.29)	0.009 (0.008)	0.013 (0.012)	E
4-04-00X-XX	Internal Floating Roof - Vapor primary and secondary seal	0.84 (0.76)	1.18 (1.07)	0.008 (0.007)	0.011 (0.010)	E
4-04-00X-XX	Internal Floating Roof - Uncontrolled fitting losses ^e	2.60 (2.36)	3.65 (3.31)	0.023 (0.021)	0.033 (0.030)	E
4-04-00X-XX	Internal Floating Roof - Controlled fitting losses ^d	1.77 (1.61)	2.48 (2.25)	0.016 (0.014)	0.022 (0.020)	E
4-04-00X-XX	Internal Floating Roof - Deck seam losses	2.29 (2.08)	3.20 (2.90)	0.021 (0.019)	0.029 (0.026)	E
4-04-00X-XX	Internal Floating Roof - Working losses primary and secondary seal	-- ^e (-- ^f)	-- ^e (-- ^f)	-- ^e (-- ^f)	-- ^e (-- ^f)	E
4-04-00X-XX	External Floating Roof - Standing Storage losses - Primary seal	15.43 (14.00)	21.61 (19.61)	0.139 (0.126)	0.194 (0.176)	E
4-04-00X-XX	External Floating Roof - Standing Storage losses - Secondary seal	6.91 (6.27)	9.69 (8.79)	0.062 (0.056)	0.087 (0.079)	E

(continued)

TABLE 6-17. CONTINUED

SCC Number	Storage Method	Gasoline Vapor VOC Emission Factor ^{a,b} ton/yr/Tank (Mg/yr/Tank)		Benzene Emission Factor ^c ton/yr/Tank (Mg/yr/Tank)		Emission Factor Rating
		Non-Winter	Winter	Non-Winter	Winter	
4-04-00X-XX	External Floating Roof - Standing Storage losses - Primary and secondary fittings	5.10 (4.63)	7.03 (6.38)	0.046 (0.042)	0.063 (0.057)	E
4-04-00X-XX	External Floating Roof- Standing Storage losses - Working losses	-- ^g (-- ^h)	-- ^g (-- ^h)	-- ^g (-- ^h)	-- ^g (-- ^h)	E

Source: Reference 158.

- ^a Emission factors calculated with equations from Chapter 4.3 of AP-42 (TANKS program version 1.0), using a non-winter RVP of 9.3 psia, a winter RVP of 12.8 psia, and a temperature of 60 °F. The reader should be aware that the TANKS program is regularly updated and that the latest version of the program should be used to calculate emission factors. At the time this document was printed, version 3.1 of the TANKS program was available.
- ^b Assumes storage vessels at pipeline breakout stations have a capacity of 50,000 bbl (8,000 m³), a diameter of 100 feet (30 meters), and a height of 40 feet (12 meters).
- ^c Calculated assuming the “typical” level of control in the “TANKS” program.
- ^d Calculated assuming the “Controlled” level of control in the “TANKS” program.
- ^e Gasoline vapor emission factor = $(5.1 \times 10^{-8} Q)$ ton/yr, where Q is the throughput through the tanks in barrels.
Benzene emission factor = $(4.6 \times 10^{-10} Q)$ ton/yr.
- ^f Gasoline vapor emission factor = $(4.6 \times 10^{-8} Q)$ Mg/yr, where Q is the throughput through the tanks in barrels.
Benzene emission factor = $(4.1 \times 10^{-10} Q)$ Mg/yr.
- ^g Gasoline vapor emission factor = $(8.1 \times 10^{-8} Q)$ ton/yr, where Q is the throughput through the tanks in barrels.
Benzene emission factor = $(7.3 \times 10^{-10} Q)$ ton/yr.
- ^h Gasoline vapor emission factor = $(7.3 \times 10^{-8} Q)$ Mg/yr, where Q is the throughput through the tank in barrels.
Benzene emission factor = $(6.6 \times 10^{-10} Q)$ Mg/yr.

“--” means data not available.

should have been captured and to average 30 percent. Because terminal controls are usually found in areas where trucks are required to collect vapors after delivery of product to bulk plants or service stations (balance service), the gasoline vapor emission factor associated with uncontrolled truck leakage was assumed to be 30 percent of the uncontrolled balance service truck loading factor ($980 \text{ mg/liter} \times 0.30 = 294 \text{ mg/liter}$).¹⁶⁰ Thus the emission factor for benzene emissions from uncontrolled truck leakage is 2.6 mg/liter, based on a benzene/vapor ratio of 0.009.

6.4.3 Benzene Emissions from Service Stations

The discussion on service station operations is divided into two areas: the filling of the underground storage tank (Stage I) and automobile refueling (Stage II). Although terminals and bulk plants also have two distinct operations (tank filling and truck loading), the filling of the underground tank at the service station ends the wholesale gasoline marketing chain. The automobile refueling operations interact directly with the public so that control of these operations can be performed by putting control equipment on either the service station or the automobile.

Stage I Emissions at Service Stations

Normally, gasoline is delivered to service stations in large tank trucks from bulk terminals or smaller account trucks from bulk plants. Emissions are generated when hydrocarbon vapors in the underground storage tank are displaced to the atmosphere by the gasoline being loaded into the tank. As with other loading losses, the quantity of the service station tank loading loss depends on several variables, including the quantity of liquid transferred, size and length of the fill pipe, the method of filling, the tank configuration and gasoline temperature, vapor pressure, and composition. A second source of emissions from service station tankage is underground tank breathing. Breathing losses tend to be minimal for underground storage tanks due to nearly constant ground temperatures and are primarily the result of barometric pressure changes.

Stage II Emissions of Service Stations

In addition to service station tank loading losses, vehicle refueling operations are considered to be a major source of emissions. Vehicle refueling emissions are attributable to vapor displaced from the automobile tank by dispensed gasoline and to spillage. The major factors affecting the quantity of emissions are dispensed fuel temperature, differential temperature between the vehicle's tank temperature and the dispensed fuel temperature, and fuel Reid vapor pressure (RVP).^{161,162} Several other factors that may have an effect upon refueling emissions are: fill rate, amount of residual fuel in the tank, total amount of fill, position of nozzle in the fill-neck, and ambient temperature. However, the magnitude of these effects is much less than that for any of the major factors mentioned above.¹⁶¹

Spillage loss is made up of configurations from prefill and postfill nozzle drip and from spit-back and overflow from the vehicle's fuel tank filler pipe during filling. Table 6-18 lists the uncontrolled emission factors for a typical gasoline service station.^{160,163} This table includes an emission factor for displacement losses from vehicle refueling. However, the following approach is more accurate to estimate vehicle refueling emissions.

Emissions can be calculated using MOBILE 5a, EPA's mobile source emission factor computer model. MOBILE 5a uses the following equation:¹⁶³

$$E_r = 264.2 [(-5.909) - 0.0949 (\Delta T) + 0.0884 (T_D) + 0.485 (RVP)]$$

where:

E_r	=	Emission rate, mg VOC/l of liquid loaded
RVP	=	Reid vapor pressure, psia (see Table 6-19) ¹⁶³
ΔT	=	Difference between the temperature of the fuel in the automobile tank and the temperature of the dispensed fuel, °F (see Table 6-20) ¹⁶¹
T_D	=	Dispensed fuel temperature, °F (see Table 6-21) ¹⁶⁴

Using this emission factor equation, vehicle refueling emission factors can be derived for specific geographic locations and for different seasons of the year.

TABLE 6-18. GASOLINE VAPOR AND BENZENE EMISSION FACTORS FOR
A TYPICAL SERVICE STATION

SCC Number	Emission Source	Gasoline Vapor Emission Factor ^a lb/1000 gal (mg/liter)	Benzene Emission Factor ^b lb/1000 gal (mg/liter)	Emission Factor Rating
4-06-003-01	Underground Storage Tanks - Tank Filling Losses - Splash Fill	11.5 (1,380)	0.104 (12.4)	E
4-06-003-02	Underground Storage Tanks - Tank Filling Losses - Submerged Fill	7.3 (880)	0.066 (7.9)	E
4-06-003-06	Underground Storage Tanks - Tank Filling Losses - Balanced Submerged Filling ^c	0.3 (40)	0.003 (0.4)	E
4-06-003-07	Underground Storage Tanks - Breathing Losses	1.0 (120)	0.009 (1.1)	E
4-06-004-01	Vehicle Refueling ^d - Displacement Losses			
	- Uncontrolled	11.0 (1,320)	0.099 (11.9)	E
	- Controlled	1.1 (132)	0.0099 (1.2)	E
4-06-004-02	Vehicle Refueling ^d - Spillage	0.7 (84)	0.0063 (0.76)	E

Source: References 160 and 163.

^a Typical service station has a gasoline throughput of 190,000 liters/month (50,000 gallons/month).

^b Based on gasoline emission factor and an average benzene/VOC ratio of 0.009.

^c Calculated using a Stage I control efficiency of 95 percent.

^d Vehicle refueling emission factors can also be derived for specific geographic locations and for different seasons of the year using the MOBILE 5a, EPA's mobile source emission factor computer model.¹⁶¹

In the absence of specific data, Tables 6-19, 6-20, and 6-21 may be used to estimate refueling emissions. Tables 6-19, 6-20, and 6-21 list gasoline RVPs, ΔT , and T_D values respectively for the United States as divided into six regions:

- Region 1: Connecticut, Delaware, Illinois, Indiana, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Virginia, West Virginia, and Wisconsin.
- Region 2: Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, and Tennessee.
- Region 3: Arizona, New Mexico, Oklahoma, and Texas.
- Region 4: Colorado, Iowa, Kansas, Minnesota, Missouri, Montana, Nebraska, North Dakota, South Dakota, and Wyoming.
- Region 5: California, Nevada, and Utah.
- Region 6: Idaho, Oregon, and Washington.

6.4.4 Control Technology for Marine Vessel Loading

Marine vapor control systems can be divided into two categories: vapor recovery systems and vapor destruction systems. There are a wide variety of vapor recovery systems that can be used with vapor collection systems. Most of the vapor recovery systems installed to date include refrigeration, carbon adsorption/absorption, or lean oil absorption. Three major types of vapor destruction or combustion systems that can operate over the wide flow rate and heat content ranges of marine applications are: open flame flares, enclosed flame flares, and thermal incinerators.¹⁶⁵

When selecting a vapor control system for a terminal, the decision on recovering the commodity depends on the nature of the VOC stream (expected variability in flow rate and hydrocarbon content), and locational factors, such as availability of utilities and distance from the tankship or barge to the vapor control system. The primary reason for selecting incineration is that many marine terminals load more than one commodity.^{159,164}

TABLE 6-19. RVP LIMITS BY GEOGRAPHIC LOCATION

State	Weighted average		
	Summer (Apr.-Sep.)	Winter (Oct.-Mar.)	Annual
Alabama	8.6	12.8	10.6
Alaska	13.9	15.0	14.3
Arizona	8.4	11.6	10.0
Arkansas	8.5	13.5	10.7
California	8.6	12.6	10.6
Colorado	8.6	13.1	10.7
Connecticut	9.7	14.5	12.0
Delaware	9.7	14.3	11.9
District of Columbia	8.8	14.1	11.4
Florida	8.7	12.9	10.7
Georgia	8.6	12.8	10.7
Hawaii	11.5	11.5	11.5
Idaho	9.5	13.2	11.3
Illinois	9.7	14.2	12.0
Indiana	9.7	14.3	11.9
Iowa	9.6	14.2	11.8
Kansas	8.6	13.1	10.8
Kentucky	9.6	14.0	11.7
Louisiana	8.6	12.8	10.6
Maine	9.6	14.5	11.9
Maryland	9.0	14.3	11.6
Massachusetts	9.7	14.5	12.0
Michigan	9.7	14.5	12.0
Minnesota	9.7	14.3	11.8
Mississippi	8.6	12.8	10.7
Missouri	8.7	13.8	11.1
Montana	9.5	14.3	11.7

(continued)

TABLE 6-19. CONTINUED

State	Weighted average		
	Summer (Apr.-Sep.)	Winter (Oct.-Mar.)	Annual
Nebraska	9.5	13.5	11.4
Nevada	8.5	12.5	10.4
New Hampshire	9.7	14.5	12.0
New Jersey	9.7	14.4	12.1
New Mexico	8.5	12.4	10.3
New York	9.7	14.5	12.0
North Carolina	8.8	13.6	11.1
North Dakota	9.7	14.2	11.7
Ohio	9.7	14.3	11.9
Oklahoma	8.6	12.9	10.7
Oregon	9.0	13.9	11.2
Pennsylvania	9.7	14.5	12.0
Rhode Island	9.7	14.5	12.1
South Carolina	9.0	13.3	11.0
South Dakota	9.5	13.5	11.3
Tennessee	8.8	13.6	11.1
Texas	8.5	12.5	10.4
Utah	8.7	13.3	10.9
Vermont	9.6	14.5	12.0
Virginia	8.8	14.0	11.3
Washington	9.7	14.3	11.9
West Virginia	9.7	14.3	11.9
Wisconsin	9.7	14.3	11.9
Wyoming	9.5	13.6	11.5
Nationwide Annual Average	9.4		11.4
Nonattainment Annual Average	9.2		11.3

Source: Reference 163.

TABLE 6-20. SEASONAL VARIATION FOR TEMPERATURE DIFFERENCE
BETWEEN DISPENSED FUEL AND VEHICLE FUEL TANK^a

	Temperature difference (°F)				
	Average annual	Summer (Apr.-Sep.)	Winter (Oct.-Mar.)	5-Month Ozone Season (May-Sep.)	2-Month Ozone Season (July-Aug.)
National average	4.4	8.8	-0.8	9.4	9.9
Region 1	5.7	10.7	-0.3	11.5	12.5
Region 2	4.0	6.8	0.9	7.5	8.2
Region 3	3.7	7.6	-0.4	7.1	7.0
Region 4	5.5	11.7	-2.4	12.1	13.3
Region 5	0.1	3.9	-4.4	5.1	3.2

Source: Reference 161.

^a Region 6 was omitted, as well as Alaska and Hawaii.

TABLE 6-21. MONTHLY AVERAGE DISPENSED LIQUID TEMPERATURE (T_D)

	Weighted average		
	Summer (Apr.-Sep.)	Winter (Oct.-Mar.)	(Annual)
National average	74	58	66
Region 1	70	51	61
Region 2	85	76	81
Region 3	79	62	70
Region 4	74	56	65
Region 5	79	63	72
Region 6	64	50	57

Source: Reference 164.

For additional information on emission controls at marine terminals refer to References 159 and 165.

6.4.5 Control Technology for Gasoline Transfer

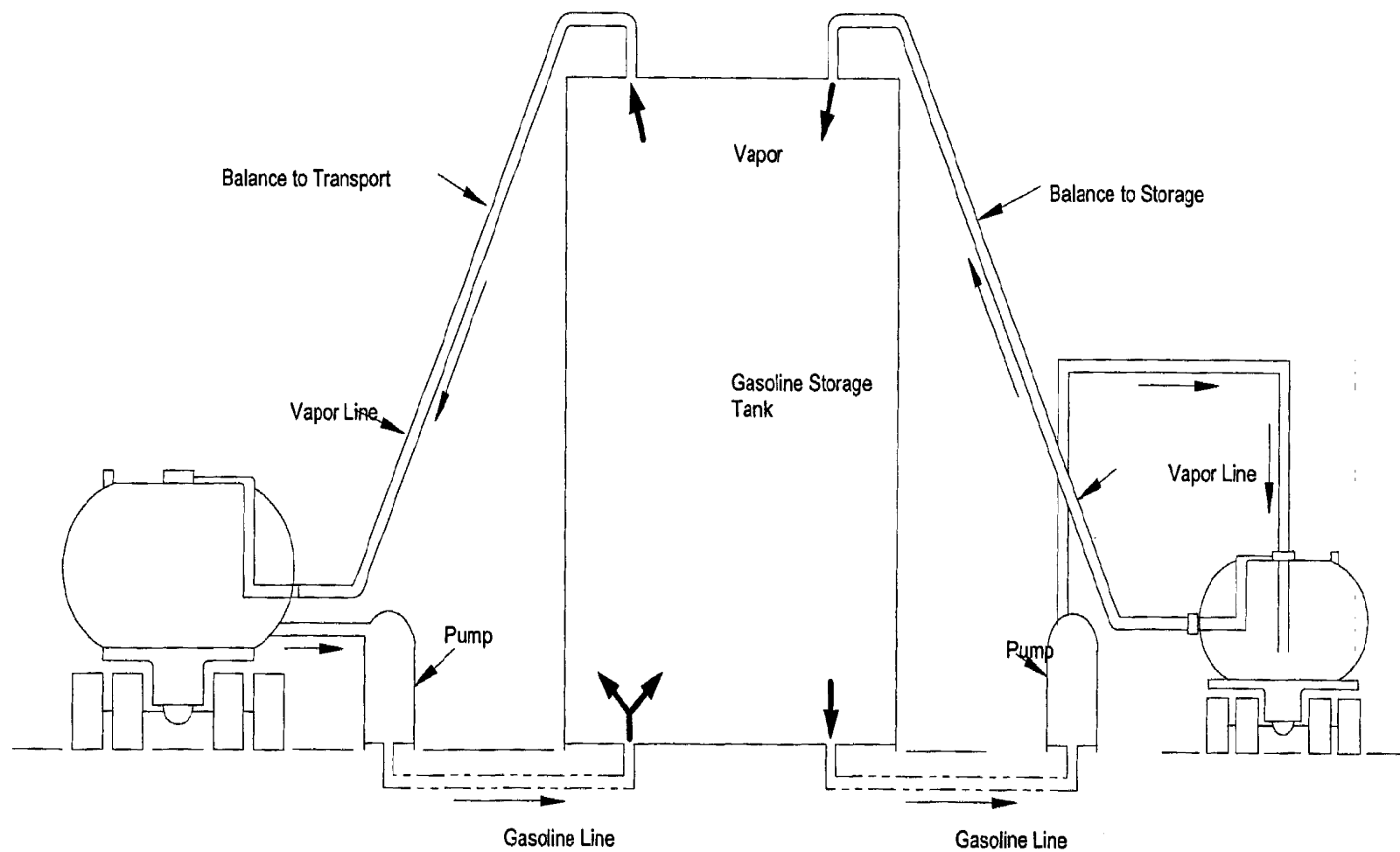
At many bulk terminals and bulk plants, benzene emissions from gasoline transfer are controlled by CTG, NSPS, and new MACT programs. Control technologies include the use of a vapor processing system in conjunction with a vapor collection system.¹⁶⁰ Vapor balancing systems, consisting of a pipeline between the vapor spaces of the truck and the storage tanks, are closed systems. These systems allow the transfer of displaced vapor into the transfer truck as gasoline is put into the storage tank.¹⁶⁰

Also, these systems collect and recover gasoline vapors from empty, returning tank trucks as they are filled with gasoline from storage tanks. The control efficiency of the balance system ranges from 93 to 100 percent.¹⁵⁷ Figure 6-4 shows a Stage I control vapor balance system at a bulk plant.¹⁶⁰

At service stations, vapor balance systems contain the gasoline vapors within the station's underground storage tanks for transfer to empty gasoline tank trucks returning to the bulk terminal or bulk plant. Figure 6-5 shows a diagram of a service station vapor balance system.¹⁶⁰ For more information on Stage II controls refer to Section 6.4.7.

6.4.6 Control Technology for Gasoline Storage

The control technologies for benzene emissions from gasoline storage involve upgrading the type of storage tank used or adding a vapor control system. For fixed-roof tanks, emissions are most readily controlled by installation of internal floating roofs. An internal floating roof reduces the area of exposed liquid surface on the tank and, therefore,



Transport Truck Unloading

Account Truck Loading

Figure 6-4. Bulk Plant Vapor Balance System (Stage I)

Source: Reference 160.